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(7) Pressure-volume-temperature analysis, if available; and

(8) A table listing the wells and completions, and indicating which sands and fault blocks will be targeted for completion or recompletion.

(c) Map interpretations which includes for each reservoir in the field:

(1) Structure maps consisting of top and base of sand maps showing well and seismic shot point locations;

(2) Isopach maps for net sand, net oil, net gas, all with well locations;

(3) Maps indicating well surface and bottom hole locations, location of development facilities, and shot points; and

(4) An explanation for excluding the reservoirs you are not planning to develop.

(d) Reservoir-specific data which includes:

(1) Probability of reservoir occurrence with hydrocarbons;

(2) Probability the hydrocarbon in the reservoir is all oil and the probability it is all gas;

(3) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for the parameters used to estimate reservoir size, *i.e.*, acres and net thickness;

(4) Most likely values for porosity, salt water saturation, volume factor for oil formation, and volume factor for gas formation;

(5) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for recovery efficiency (in percent) and oil or gas recovery (in stock-tank-barrels per acre-foot or in thousands of cubic feet per acre foot);

(6) A gas/oil ratio distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each reservoir;

(7) A yield distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each gas reservoir; and

(8) Reserve or resource distribution by reservoir.

(e) Aggregated reserve and resource data which includes:

(1) The aggregated distributions for reserves and resources (in BOE) and oil fraction for your field computed by the resource module of our RSVP model;

(2) A description of anticipated hydrocarbon quality (*i.e.*, specific gravity); and

(3) The ranges within the aggregated distribution for reserves and resources that define the development and production scenarios presented in the engineering and production reports. Typically there will be three ranges specified by two positive reserve and resource points on the aggregated distribution. The range at the low end of the distribution will be associated with the conservative development and production scenario; the middle range will be related to the most likely development and production scenario; and, the high end range will be consistent with the optimistic development and production scenario.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1879, Jan. 15, 2002]

§ 203.87 What is in an engineering report?

This report defines the development plan and capital requirements for the economic evaluation and must contain the following elements.

(a) A description of the development concept (e.g., tension leg platform, fixed platform, floater type, subsea tieback, etc.) which includes:

(1) Its size along with basic design specifications and drawings; and

(2) The construction schedule.

(b) An identification of planned wells which includes:

(1) The number;

(2) The type (platform, subsea, vertical, deviated, horizontal);

(3) The well depth;

(4) The drilling schedule;

(5) The kind of completion (single, dual, horizontal, etc.); and

(6) The completion schedule.

(c) A description of the production system equipment which includes:

(1) The production capacity for oil and gas and a description of limiting component(s);

(2) Any unusual problems (low gravity, paraffin, etc.);

(3) All subsea structures;

(4) All flowlines; and

(5) Schedule for installing the production system.

(d) A discussion of any plans for multi-phase development which includes the conceptual basis for developing in phases and goals or milestones required for starting later phases.

(e) A set of development scenarios consisting of activity timing and scale associated with each of up to three production profiles (conservative, most likely, optimistic) provided in the production report for your field (§ 203.88). Each development scenario and production profile must denote the likely events should the field size turn out to be within a range represented by one of the three segments of the field size distribution. If you send in fewer than three scenarios, you must explain why fewer scenarios are more efficient across the whole field size distribution.

[63 FR 2618, Jan. 16, 1998, as amended at 67 FR 1880, Jan. 15, 2002]

§ 203.88 What is in a production report?

This report supports your development and production timing and product quality expectations and must contain the following elements.

(a) Production profiles by well completion and field that specify the actual and projected production by year for each of the following products: oil, condensate, gas, and associated gas. The production from each profile must be consistent with a specific level of reserves and resources on the aggregated distribution of field size.

(b) Production drive mechanisms for each reservoir.

§ 203.89 What is in a cost report?

This report lists all actual and projected costs for your field, must explain and document the source of each cost estimate, and must identify the following elements.

(a) *Sunk costs.* Report sunk costs in dollars not adjusted for inflation and only if you have documentation.

(b) Appraisal, delineation and development costs. Base them on actual spending, current authorization for expenditure, engineering estimates, or analogous projects. These costs cover:

(1) Platform well drilling and average depth;

(2) Platform well completion;

(3) Subsea well drilling and average depth;

(4) Subsea well completion;

(5) Production system (platform); and

(6) Flowline fabrication and installation.

(c) *Production costs based on historical costs, engineering estimates, or analogous projects.* These costs cover:

(1) Operation;

(2) Equipment; and

(3) Existing royalty overrides (we will not use the royalty overrides in evaluations).

(d) *Transportation costs, based on historical costs, engineering estimates, or analogous projects.* These costs cover:

(1) Oil or gas tariffs from pipeline or tankerage;

(2) Trunkline and tieback lines; and

(3) Gas plant processing for natural gas liquids.

(e) *Abandonment costs, based on historical costs, engineering estimates, or analogous projects.* You should provide the costs to plug and abandon only wells and to remove only production systems for which you have not incurred costs as of the time of application submission. You should also include a point estimate or distribution of prospective salvage value for all potentially reusable facilities and materials, along with the source and an explanation of the figures provided.

(f) *A set of cost estimates consistent with each one of up to three field-development scenarios and production profiles (conservative, most likely, optimistic).* You should express costs in constant real dollar terms for the base year. You may also express the uncertainty of each cost estimate with a minimum and maximum percentage of the base value.

(g) *A spending schedule.* You should provide costs for each year (in real dollars) for each category in paragraphs (a) through (f) of this section.

(h) *A summary of other costs which are ineligible for evaluating your need for relief.* These costs cover:

(1) Expenses before first discovery on the field;

(2) Cash bonuses;

(3) Fees for royalty relief applications;